EB-2022-0086
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ONTARIO ENERGY BOARD

IN THE MATTER OF the Ontario Energy Board Act, 1998, S.O. 1998, c. 15, Schedule B, and in particular, sections 90 (1) and 97 thereof;

AND IN THE MATTER OF an Application by Enbridge Gas Inc. for an Order or Orders granting leave to construct natural gas pipelines and ancillary facilities from the Township of Dawn-Euphemia to St. Clair Township;

AND IN THE MATTER OF an Application by Enbridge Gas Inc. for an Order or Orders approving the proposed forms of agreements for Pipeline Easement and Options for Temporary Land Use.

ENBRIDGE GAS INC.

ARGUMENT-IN-CHIEF

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A. <u>Introduction</u>

1. This is the Argument-in-Chief ("AIC") of Enbridge Gas Inc. ("Enbridge Gas" or the "Company") in its leave-to-construct application in respect of the Dawn to Corunna Replacement Project (the "Project"). The scope of the Project includes the retirement and abandonment of 7 of the 11 existing reciprocating compressor units at the Corunna Compressor Station ("CCS") located in St. Clair Township and the construction of approximately 20 km of NPS 36 pipeline from the Dawn Operations Centre in the Township of Dawn Euphemia to the CCS. The Project also includes work at the two stations to tie-in the new pipeline.

2. Enbridge Gas requests the following orders from the Board:
    i. Pursuant to Section 90(1) of the *Ontario Energy Board Act*, 1998 (the "Act"), an order granting leave to construct the Project; and
    ii. Pursuant to Section 97 of the Act, an order or orders approving the form of Pipeline Easement agreement and the form of Temporary Land Use agreement.[1]

3. Enbridge Gas submits that the Project is in the public interest and the requested relief should be granted. <u>The CCS is critical to satisfying design day demand and because of condition and obsolescence there is an unacceptable risk of failure which cannot be managed effectively or economically without the Project. Relative to the Project, there is no other alternative that is as economic or cost effective and that adequately reduces the reliability and safety risk</u>.

4. The balance of this AIC discusses the need, alternatives, costs and economics, engineering and construction, environmental and land-related matters, and Indigenous consultation relating to the Project.

    - **Section B** (paragraphs 5 to 10) explains why maintaining reliable access to underground storage (capacity & deliverability) is critically important to ensuring energy security for EGD rate zone customers.

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[1] See Exhibit G-1-1, Attachments 3 and 4, respectively.

- **Section C** explains the obsolescence and reliability risks (paragraphs 13 to 26) associated with the existing 50+ year old CCS compressor units (e.g., challenges sourcing replacement parts and rapidly declining asset health leading to extended and more frequent maintenance/repair downtime and increasing risk to customers of outage/shortfall), and process safety risks (paragraphs 27 to 30) to Company personnel operating and maintaining these units in their current configuration.
- **Section D** (paragraphs 34 to 56) explains the various non-facility, facility, and repair alternatives assessed by Enbridge Gas and the criteria by which alternatives were compared (e.g., physical characteristics, cost, NPV, risk, availability, etc) to conclude that the proposed TR7/NPS 36 pipeline is the preferred alternative in all respects. This section summarizes: (i) the results of ICF's evaluation of and conclusion that supply-side alternatives introduce unacceptable incremental risk and considerable incremental cost compared to the Project (paragraph 37); and (ii) assessments of market-based storage (paragraph 38), delivered supply (paragraph 39), upstream pipeline capacity (paragraph 40), and enhanced targeted energy efficiency programming (paragraph 41) all of which present unique incremental risks (e.g., availability, price volatility, and contracting) and will cost ratepayers significantly more than the proposed Project.
- **Section E** (paragraphs 57 to 61) sets out the estimated cost for the proposed Project (pipeline and ancillary), the reasonability of these costs relative to comparable projects, and discusses the continued allocation of such costs to EGD rate zone customers in the same manner as the CCS compressor units being replaced.
- **Section F** (paragraphs 62 to 67) summarizes the Company's planned engineering and construction practices and construction schedule, and its commitments to adhere to all applicable standards (internal/external) and to obtain all necessary permits and approvals.
- **Section G** (paragraphs 68 to 72) summarizes the findings of the Environmental Report and the Company's commitment to adhere to the mitigation measures set

out therein, including the development of an Environmental Protection Plan, in order to ensure that no significant cumulative effects result from construction of the Project.

- **Section H** (paragraphs 73 to 77) summarizes the lands rights required for the Project, the forms of agreement (easement and temporary land use) proposed to be utilized, and the status of ongoing negotiations with landowners.
- **Section I** (paragraphs 78 to 81) summarizes the Company's commitment to meaningful engagement with potentially affected Indigenous Communities in relation to the Project and actions taken in this regard on behalf of the Crown to consult with the same.
- **Section J** summarizes the relief sought by Enbridge Gas in this proceeding (for an order of the Board granting leave to construct and approval of the forms of lands agreement proposed).

B. Critical Importance of the CCS

5. As one of North America's largest natural gas market hubs, the Dawn Hub is a critical source of competitively priced energy supply for Ontario gas consumers. Essential to this competitively priced energy supply is the Dawn Hub's underground gas storage that must provide highly reliable service year-round and, in particular, during design conditions relating to cold winter weather when Ontario gas consumers are the most vulnerable. As one of the two main compression locations at the Dawn Hub, the CCS, together with the Dawn Operations Centre, is a critical component in the provision of storage and the delivery of energy to gas consumers in the EGD rate zone. The EGD rate zone includes over 2.3 million residential, commercial and industrial customers spread across the Greater Toronto Area, the Niagara Peninsula, Ottawa, Barrie, Midland, Peterborough and Brockville as well as other communities.

6. To ensure effective and economic storage access, the compression facilities must operate reliably and safely to fill and empty underground storage reservoirs when needed.[2] Using 11 reciprocating compressor units totaling 36,750 hp, the CCS

[2] Exhibit B-1-1, pp. 5-10, paras. 13-22.

transports natural gas to and from underground storage facilities via the Dawn Operations Centre to transmission pipelines for use in the EGD rate zone.[3]

7. The 11 CCS compressor units (named K701 to K711[4]) serve a range of functions, depending on the operating scenario and pipeline system pressure differentials. During storage <u>withdrawal</u>, units K701-703 are initially relied on at higher suction pressures and smaller pressure differentials while units K705-708 are relied on at lower suction pressures and larger pressure differentials.[5] On design day, 10 of the 11 compressor units operate to compress gas from CCS towards the Dawn Operations Centre (with K711 held in reserve as a Loss of Critical Unit ("LCU") asset).[6] During storage <u>injection</u>, K701-K703 are initially relied on at lower discharge pressures and smaller pressure differentials, while K705-708 are relied on at higher discharge pressures and pressure differentials.[7]

8. On design day, if any 1 of the 10 operating CCS units is out of service for a prolonged period of time and replaced in function by unit K711, no LCU unit would be available should another unit be lost. This scenario could result in a high consequence event, which would compromise the reliability of the system and the ability to serve firm customers.[8] Due to the unique nature of each CCS compressor unit relating to its configuration, and the specific compression needs at the time (low, medium, or high pressure) during injection or withdrawal, the remaining compressor units that have not failed may not be suitable to avoid a shortfall.[9]

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[3] Exhibit B-1-1, p. 6, para. 15.

[4] The compressor units follow the naming convention K701 through K711 based on their sequence of installation dating from 1964 to 1995 and are housed within three separate buildings. Compressors K701-K705 are located within compressor building 1, K706-K710 in compressor building 2, and K711 in compressor building 3 (see Exhibit B-1-1, p. 6, para. 15).

[5] Exhibit B-1-1, p. 9, para. 21.

[6] Exhibit B-1-1, p. 8, para. 19.

[7] Three units out of K705-K708 are required to operate simultaneously to support peak compression conditions (typically occurring between mid-July to mid-September) (Exhibit B-1-1, p. 9, para. 21).

[8] Exhibit B-1-1, p. 14, para 32.

[9] *Ibid.* Please also see discussion regarding the recent outage of unit K705 set out in paras. 15-21 below.

9. Enbridge Gas has an obligation to meet the firm demands of its customers and must assess its assets to continually verify that they remain reliable, suitable and fit for continued service. With respect to the CCS compressor units, asset studies indicate that the health and maintainability of seven units are in serious decline or obsolete, threatening system reliability and employee safety. As detailed in the Company's evidence and highlighted in this AIC, the Project effectively mitigates these risks. Specifically, constructing the 20 km of NPS 36 pipeline (referred to as the TR7 pipeline) from the Dawn Operations Center to the CCS will enable Enbridge Gas to retire seven compressor units (K701-K703 and K705-K708) and maintain equivalent capacity/deliverability (including all required injection and withdrawal modes of operation described above).[10]

10. Units K704, K709, K710 and K711 cannot be replaced by the Project since they provide specific functions in the CCS injection and withdrawal seasonal cycles.[11] On injection, units K704 and K711 will continue to be required to compress gas arriving from Dawn to fill the top end of the storage pools to their planned maximum operating pressure.[12] On withdrawal, units K709 and K710 will continued to be required to provide a low suction pressure from the CCS to allow the pools to reach cushion pressure or minimum operating pressure.[13] Once the Project is completed, the first stage of injection or withdrawal capability currently provided by the 7 CCS compressor units to be abandoned will be replaced with compression capacity at the Dawn Operations Centre via the new TR7 pipeline, physically integrating Tecumseh (EGD) and Dawn (Union) storage facilities and operations.[14] Units K704, K709, K710 and K711 (or equivalent horsepower (hp)) will always be required at CCS to achieve a full

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[10] Exhibit B-1-1, pp. 11-12, para. 26.

[11] These compressors (or equivalent horsepower) will always be required at CCS to achieve a full cycle of the 9 storage pools connected to the CCS, including after the completion of the Project (Exhibit B-1-1, pp. 9-10, para. 22).

[12] Exhibit I.Staff.11 a).

[13] *Ibid*.

[14] Technical Conference Day 1 REVISED Transcript, pp. 42, ln. 1-4 & 13-26; p. 210, ln. 21-28.

cycle of the 9 storage pools connected to the CCS, including after the completion of the Project.[15]

C. <u>Project Need</u>

11. Without the Project, there are unmitigated serious and material risks related to obsolescence, reliability, and employee safety.[16] The need is grounded in the known condition and associated failure risk of CCS compressor units (including all relevant components). This latter aspect has been informed and verified by rigorous technical studies and expert input, which include:
    i. Asset Health Review ("AHR")[17] – A 2018 study that assessed the declining reliability of CCS compressor assets. The AHR was updated in 2021 and failure data was used as the inputs for the RAM Study (defined below).
    ii. RAM Study – The Reliability, Availability and Maintainability ("RAM") study[18] for the CCS quantifies the estimated mean shortfall due to asset failure and the associated financial consequence and risk to the Company and its customers.
    iii. Enbridge Gas CCS Site Wide Quantitative Risk Assessment ("QRA")[19] – This QRA evaluates the potential risk level for workers due to accidental releases of hazardous materials, mainly natural gas, from loss of containment scenarios from the CCS.
    iv. DNV GL Review of the CCS QRA[20] – Expert review and evaluation of the QRA. This QRA and the other QRA reports noted are collectively referred to as the "QRA" below.

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[15] Exhibit B-1-1, pp. 9-10, para. 22; Exhibit I.Staff.11 a).

[16] While Enbridge Gas has implemented short-term risk mitigants to help manage risks related to occupancy levels within buildings containing pressurized equipment for a limited period of time, they are insufficient strategies in the long term as they do not resolve the risks of obsolescence, reliability and safety and introduce other unique challenges and risks over the longer term (Exhibit B-1-1, pp. 26-28, paras. 52-53).

[17] Exhibit I.ED.1 c.), Attachment 1.

[18] Exhibit B-1-1, Attachment 2.

[19] Exhibit I.CME.1, Attachment 1.

[20] Exhibit I.CME.1, Attachment 2.

12. The AHR, RAM Study and QRA for the CCS all support the Company's understanding of the obsolescence, reliability and safety risks that must be addressed to avoid costly/disruptive supply shortfall scenarios as well as potentially catastrophic safety incidents.

Obsolescence and Reliability Risks

13. Compressor units K701-K703 account for 20% of the available compressor power at CCS. All three units are the same make, model (KVT) and vintage (1964). The KVT compressor model has been out of production for 40 years. As a result, there are only 19 of these units in operation globally and only 1 of those operating units is similar to units K701-K703.[21] The original equipment manufacturer does not stock spares in inventory for cast or forged components (e.g., crankshafts). This means that long lead times result when repairs require replacement components to be cast or forged, cured, custom machined, and polished.[22]

14. The obsolescence of compressor units K701-K703 hampers the Company's ability to maintain these units, increases repair time and elevates risk especially since operational flexibility becomes limited or non-existent (depending on demand conditions) if other failures occur. Further, the risk associated with obsolescence of these units is amplified by reliability declines observed in the AHR/RAM Study which indicates that units K701, K702 and K703 present the lowest engine and compressor reliability amongst all of the compressor units at CCS.[23]

15. CCS compressor units K705-K708 provide compression to mid-range pressure and account for 41% of the compressor power at the CCS. These 4 units are of the same make, model (KVR) and range in vintage (1970-1974). The OEM is increasingly challenged to supply parts in a timely manner for these units. For example, the

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[21] Having been retrofitted with low NO_x combustion systems. Across North America, there are only four compressor units of this type remaining that have been retrofit with low NO_x combustion systems, three of which are located at the CCS.

[22] Exhibit B-1-1, pp. 13-14, para 31. Also see the response at Exhibit I.EP.7 a).

[23] Exhibit B-1-1, p. 15, para. 33.

Company sought to replace a broken crankshaft on unit K705 in 2018, which led to 18 months of unit downtime. This included sourcing the replacement crankshaft from England (which took 8 months) and installing the crankshaft according to an elaborate, OEM-approved repair process.[24]

16. During the unit K705 outage, the CCS had no spare mid-range pressure units, and units K706-K708 were operated at a greater number of hours as a result. This further exacerbated their respective reliability risk and obsolescence issues. If a single additional compressor unit failed during the prolonged outage, full storage inventory levels would not have been achieved by the end of the 2018 injection season. This would have forced the Company to consider other physical and/or market-based storage and supply alternatives at significant incremental cost and risk to ratepayers.[25]

17. Going forward, if similar repairs were required on any one of the CCS compressor units, this could expose storage operations to elevated risks and vulnerabilities and further exacerbate reliability and obsolescence issues for the remaining units due to increased run time.

18. During the 18 months required to resolve the unit K705 crankshaft repair (as discussed above), had a second compressor failure occurred on a high demand day during January through March, the Company could have experienced a volumetric shortfall ranging from 186 TJ/d (for failures of any of units K701, K702 or K703) to 230 TJ/d (for failures of any of units K706, K707 or K708). This scenario would have required the Company to procure volumes above ground at Dawn as a delivered service for the period that the second compressor was unavailable.[26]

19. During withdrawal season, using the last 10 years of Dawn pricing data across January, February, and March, the loss of an additional CCS unit on a design day (in addition to unit K705) would have ranged in cost for delivered supply between

[24] Exhibit B-1-1, p, 15, para. 34.
[25] Exhibit B-1-1, p. 16, para. 34.
[26] Exhibit B-1-1, p. 22, para. 46.

approximately $800,000 to $11 million for a single day.[27] A secondary unit failure of long duration could have caused a very significant financial impact to EGD rate zone customers. If these volumes of gas were not able to be procured on the spot market, services to contract class customers could have been interrupted and/or up to 185,000 residential customers could have experienced an outage during the coldest time of the year (design conditions). This scenario and associated risks are unacceptable given the Company's firm service obligations.[28]

20. While unit K705 was eventually repaired and placed back into service, a longer-term and permanent solution to address these issues (with degrading mechanical equipment that is approximately 50 years old and at increasing risk of failure) is required.[29]

21. As noted above, on a design day, this risk is further exacerbated if any 1 of the 10 operating CCS units is out of service for a prolonged period of time and replaced in function by K711, as no LCU unit would be available should another unit be lost. This scenario could result in a high consequence event, which would compromise the reliability of the system and the ability to serve firm customers.[30]

22. The retirement of CCS units K701-K703 and units K705-K708 will also allow the Company to avoid planned maintenance capital expenditures estimated at more than $16 million from 2023-2032 as well as any unplanned maintenance costs resulting from unit failures. Further, as units K705-K708 are of similar makes and models (KVR) as the remaining CCS units (K704, K709, K710 and K711) that cannot be retired at this time due to their specific operational fit, retiring units K705-K708 will provide the Company with access to a variety of additional OEM spare parts that can be used to maintain the remaining units. By disassembling units K705-K708, salvaging interchangeable spare parts, and storing them within the Company's inventory for

[27] Exhibit B-1-1, pp. 15-16, para. 34.
[28] Exhibit B-1-1, p. 22, para. 46.
[29] Exhibit B-1-1, p. 16, para. 35.
[30] Exhibit B-1-1, p. 14, para 32.

future use, the risk of experiencing extended downtime for future repairs to those units (as well as the cost of the same) is expected to be significantly mitigated.[31]

AHR and RAM Study

23. Based on an AHR performed in 2018 and updated in 2021 (as part of the Company's RAM Study for the CCS, completed by DNV GL), Enbridge Gas identified serious and increasing obsolescence and reliability risks associated with the compressor units K701-K703 and K705-K708. This is due to both the amount of repair downtime experienced and system shortfall that could result from their failure considering the criticality of these facilities to meet peak design conditions.[32]

24. The AHR considers failure data from the Company's maintenance management system to calculate the probability of failure, which is in turn converted into a Storage Health Index ("SHI") to indicate the predicted time to failure for a specific asset.[33] The AHR indicated that the compression asset sub-classes (foundation, crankshaft, engine, compressor, after cooler, heating & cooling system, and valving system) are more susceptible to failures due to multiple mechanical parts and complex interdependencies, with engines and compressors having the lowest asset health and being the least reliable asset sub-classes. Further, results for CCS units K701-K703 and units K705-K708 indicate that both engine and compressor failures are expected to occur within 2 years for all units.[34]

25. The obsolescence and reliability concerns with the CCS compressor units discussed above, including maintainability and time to repair, all contribute to increased deliverability and financial risk as all units are required to operate in order to achieve design day flow rates.[35]

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[31] Exhibit B-1-1, p. 17, paras. 36-37. Also see I.FRPO.25 c) iii.
[32] Exhibit B-1-1, p. 13, para 30.
[33] The AHR is filed at Exhibit I.ED.1, Attachment 1.
[34] Exhibit B-1-1, pp. 18-19, paras. 39-41.
[35] Exhibit B-1-1, p. 21, para. 45.

26. The RAM Study relies on key inputs from the AHR to inform asset reliability, availability, and maintainability.[36] The study helps to quantify the likelihood of failure to meet the operational objectives or demands and to estimate the impact of such failure in terms of resulting shortfall compared to an expected or target demand.[37] The SHI results and the instantaneous mean time between failures for each compression asset sub-class were used to model total down times for each CCS unit over the next 5 years, according to operational cycles (injection and withdrawal).[38] According to the results of the RAM Study:

    i. Over the 5-year period, the total down time across all units is expected to be 1,300 days (including 606 days during Injection Mode and 695 days during Withdrawal Mode).
    ii. During the injection season, at least one compressor is down for maintenance or repair 77% of the time,[39] with units K704 and K701 showing the highest down times (forecasted to be 118 and 101 days, respectively).[40]
    iii. During the withdrawal season, at least one compressor is forecasted to be down for maintenance or repair 90% of the time,[41] with K701 showing the highest down time at 115 days.[42]
    iv. On injection, foundations, engines and compressors are the top 3 maintainable item contributors to shortfall, accounting for about 31%, 23% and 21% of the total shortfall, respectively. On withdrawal, compressors, foundations and engines are the top 3 maintainable item contributors to shortfall, accounting for 26%, 21% and 15% of the total shortfall, respectively.[43]

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[36] Exhibit B-1-1, pp. 17-18, para. 38; the RAM Study is filed at Exhibit B-1-1, Attachment 2.
[37] Exhibit I.CME.2, p. 6.
[38] Exhibit B-1-1, p. 21, Table 4.
[39] Exhibit I.Staff.5.
[40] Exhibit B-1-1, p. 21, para. 43.
[41] Exhibit I.Staff.5.
[42] Exhibit B-1-1, p. 22, para. 44.
[43] Exhibit B-1-1, Attachment 2, p. 8.

v. On average, more than 6,500 hours per year of downtime will be required for units K701-K703 and units K705-K708.[44]

vi. The proposed Project will improve overall system reliability and can eliminate over 4,000 hours of repair time per year.[45]

Personnel Safety Risk

27. The condition and obsolescence of the existing CCS compressor units has increased maintenance and repair work at the CCS. Recognizing the importance of safety and that the CCS represents a significant concentration of complex high pressure gas infrastructure in a contained geographic site, Enbridge Gas undertook a site-wide QRA that applied industry best practices to determine the severity of the increasing safety risks.[46] The purpose of the QRA is to evaluate the potential risk level for workers due to accidental releases of hazardous materials from loss of containment scenarios from the CCS facility and to evaluate these scenarios from the perspective of the Company's risk evaluation criteria.[47] The Company's risk evaluation thresholds are consistent with industry best practices and risk acceptance levels recommended by the proposed CSA Z662-23 Annex B - 2023 draft standard[48] as well as criteria adopted by the BC Oil & Gas Commission and UK Health & Safety Executive.[49] Based on the QRA, Enbridge Gas determined that the current configuration of compressor units results in an excessive level of process safety risk.[50]

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[44] Exhibit B-1-1, p. 28, para. 53 (iii).

[45] Exhibit B-1-1, p. 31, para. 60.

[46] See Exhibit I.SEC.10 and Exhibit I.CME.1, Attachment 1.

[47] Exhibit I.CME.1, Attachment 1, p. 3.

[48] Exhibit I.CME.2 a). Also see Exhibit JT1.6, which explains that "…the current version, CSA Z662-19, does not lay out the process and techniques by which risks should be evaluated nor any specific criteria for evaluating their significance (i.e., acceptability). The draft 2023 version of CSA Z662, to be released next year, is expected to contain guidelines on the appropriate criteria to be used in evaluating the significance of risk…".

[49] Exhibit I.CME.2, p. 5.

[50] Exhibit B-1-1, p. 11, para. 25, and p. 23, para 47.

28. Considering equipment and piping containing natural gas in key process areas at the CCS facility, the QRA results show that the CCS site exceeds the upper risk threshold for the following individuals:
    - Operator;
    - Mechanics;
    - Instrumentation Technician;
    - Electrical Technician; and
    - Chief Mechanic.[51]

29. The QRA also indicates that risks are concentrated in compressor buildings 1 and 2 of the CCS site, with building 1 having the highest risk. Based on the current station design of multiple compressor units in close proximity in a single building, an excessive level of process safety risk is present. Enbridge Gas takes the safety of all personnel (i.e., employees and contractors) and the public extremely seriously and has thus determined that the identified process safety risks require mitigation.[52]

30. It is important to recognize that catastrophic events do occur within the oil and gas and chemical industries, and their occurrence has significant impact to people, environment and property.[53] It is essential that Enbridge Gas – as the steward responsible for critical infrastructure and the personnel located in proximity – rigorously assess the safety risks from potential incidents (including catastrophic incidents that could lead to fatalities) based on available data and best practices, as it has done for the CCS in this case.[54]

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[51] Exhibit B-1-1, pp. 25-26, para. 51.

[52] *Ibid*.

[53] Non-Enbridge examples include: BP Texas City Refinery explosion (2005), fire at Consumer Gas Compressor Station in Michigan (2019); and Freeport LNG explosion in Texas (2022). Enbridge examples include: Line 6B rupture just south of the town of Marshall, Michigan (2010), and Prince George pipeline explosion in BC (2018). (Exhibit JT1.6, p. 1). Also see Exhibit B-2-1, pp. 3-4, para. 8.

[54] Technical Conference Day 1 REVISED Transcript, p. 20, ln. 10-18.

Known Serious Risks Must be Addressed

31. The conclusions of the RAM Study and QRA present clear and unique challenges to the Company since increased repair downtime for maintenance due to obsolescence and reliability risks (related to compressor unit failure) inherently increases CCS building occupancy rates for mechanics and technicians, thereby increasing employee safety risk. This in turn makes it increasingly challenging to coordinate maintenance/repair activities with operational requirements and restrictions that would limit building occupancy.

32. The results of the RAM Study support the Company's conclusions that:
    i. If no action is taken, reliability and obsolescence issues will continue to escalate going forward further increasing reliability and safety risk;
    ii. The consequences of experiencing a significant system failure and shortfall are unacceptable (both operationally and financially);
    iii. Ongoing reliance on shorter-term mitigants is not sustainable; and
    iv. A long-term solution is required.[55]

33. The most effective and reliable long-term solution is to retire and decommission units K701-K703 and units K705-K708 and to construct facilities to maintain the equivalent deliverability and storage capacity. The retirement of these 7 CCS compressor units also enables the Company to avoid planned maintenance capital expenditures estimated at more than $16 million from 2023-2032, in addition to unforeseen incremental expenditures related to unplanned outages/failures which are expected to occur at increasing frequency going forward.[56] As discussed under "Alternatives" below, no other assessed alternative would address all of the identified reliability, obsolescence and safety risks as cost-effectively as the proposed Project on a long-term basis.

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[55] Exhibit B-1-1, p. 29, para. 56.
[56] Exhibit B-1-1, p. 30, paras. 57-58.

D. Project Alternatives & The Proposed Project

34. At a direct investment cost of $206.4 million and a NPV of $200 million on a 40-year life, the Project is the least cost solution for replacing the lost storage capacity and deliverability. In establishing this fact, Enbridge Gas conducted an extensive evaluation of non-facility, facility, and repair alternatives. In each case, the alternative was uneconomic and not suitable to satisfy the required need.

35. In considering Enbridge Gas's alternatives evaluation, it is important to understand the need that must be satisfied. In this regard, for context, retiring and abandoning the 7 existing compressor units at CCS would result in the loss of 22,500 hp, which (if not replaced) would lead to: (i) reductions of 5.7 PJ in withdrawal deliverability and 14.7 PJ in injection capacity, thereby reducing EGD rate zone in-franchise storage capacity by 20 PJ from 99.4 PJ to 79.1 PJ, and (ii) a reduction of 0.67 PJ/d in design day storage withdrawal deliverability.[57] If this loss of capacity/deliverability is not replaced, storage space will be stranded, forcing Enbridge Gas to procure supply-side services at a magnitude that would significantly impact natural gas prices in Ontario.[58] For comparative purposes on a purely energy conversion basis, 20 PJ (5.6 TWh) in cost-based storage capacity is approximately equal to the embedded electrical generation capacity in the province (6 TWh), and 0.67 PJ/d (7.6 GW) is approximately equal to 74% and 83% of Ontario's nuclear and hydro generation, respectively.[59] Approximately 0.9 million EGD rate zone customers would need to be disconnected from the natural gas system in order to reduce design day demand by 0.67 PJ/d and up to 7.6 GW of incremental electricity would need to be delivered into the EGD rate zone in order to replace those natural gas volumes.[60] As far as Enbridge Gas is aware,[61] there are no plans (either in the short or longer-term) to expand electricity

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[57] Exhibit C-1-1, pp. 2-3, para. 5.

[58] As concluded by ICF, the impacts include "an average increase in annual natural gas prices at Dawn of **C$0.013 per GJ**, and an average increase in the seasonal natural gas price basis (Winter minus Summer prices) at Dawn of **$0.072/GJ** between April 2024 and March 2045." (Exhibit C-1-1, Attachment 2, p. 13).

[59] Exhibit C-1-1, pp. 5-6, para. 6.

[60] Technical Conference Day 1 REVISED Transcript, p. 131, ln. 13-27; Exhibit JT1.9.

[61] Based on the Company's understanding of the IESO's long-term plans and Annual Planning Outlook.

infrastructure in the province at the scale required to replace the energy equivalent of natural gas storage and deliverability made accessible via Tecumseh storage and the existing CCS units.[62]

a. Non-Facility Alternatives

36. Relative to the Project, on a reasonable cost comparison basis, none of the non-facility alternatives, either alone or in combination with other facility and/or non-facility alternatives, are: (i) a suitable replacement for the Project, or (ii) reduce the proposed facilities needed to replace the storage capacity lost. The non-facility alternatives considered are highlighted below.

Supply Side Alternatives

37. The Company engaged ICF Consulting to review and evaluate supply-side alternatives relative to the proposed Project. ICF evaluated a range of available options for replacing the loss in cost-based storage capacity. Relative to the Project, all of the supply-side alternatives considered introduce an unacceptable level of incremental risk to EGD rate zone customers and are considerably more costly than the proposed Project. More specifically:

    i. Relative to the Project's direct investment cost of $206.4 million and a NPV of $276 million on a 40-year life, the reduction in commodity purchase costs enabled by the Project is valued at a NPV of $794 million over a 40-year life, which on an annualized basis will more than offset the annual cost-of-service of the Project and result in a reduction in the overall cost-of-service to Enbridge Gas in-franchise customers relative to the "non replacement" option.

    ii. The alternative supply side approaches (discussed below) are projected to lead to a higher cost-of-service to Enbridge Gas in-franchise customers relative to the Project. Over the 40-year life of the Project, reliance on the least cost

[62] Exhibit C-1-1, pp. 5-6, para. 7.

alternative to the Project would lead to an increase in the cost-of-service of about $519 million relative to the Project.

iii. The Project provides significant reliability and resiliency benefits to the regional system that would not be provided by other supply side alternatives.[63]

38. *Market-Based Storage Alternative.* To replace the physical attributes provided by the seven CCS compressor units proposed to be retired and abandoned, the Company could contract for either 55.5 PJ of storage capacity with 1.2% deliverability or 14.7 PJ with 4.5% deliverability. This alternative is uneconomic since over a 40-year span the cost would range between $519 to $556 million more than the Project. Furthermore, additional risks to EGD rate zone customers are introduced because most market-based storage capacity is currently contracted and the significant capacity needed is unlikely to be available in a timely manner without significantly impacting the market price for storage. Also, storage is generally contracted for without renewal rights.[64]

39. *Delivered Services Alternative*. The purchase of a third-party delivered service at either Dawn or within the EGD rate zone as needed by Enbridge Gas to meet requirements on a set number of days per year would: (i) represent a significant increase in demand for the services (representing an increase to 18% of the Gas Supply Plan), and (ii) be much more costly to EGD rate zone customers compared to the Project ($1.2 to $2.2 billion more than the Project over 40 years).[65] Delivered services are subject to a much higher price volatility risk, whereas the utilization of the storage space associated with the CCS and Tecumseh storage facilities (including summer purchases) provides an implied hedge against winter pricing volatility that cannot be replicated by delivered services. For example, in the winter of 2013/2014 during a polar vortex weather event that depleted storage inventories faster than planned due to prolonged extreme cold, EGD rate zone customers were exposed to extreme price swings (primarily for delivered supply) as EGD incurred more than $600

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[63] Exhibit C-1-1, pp. 9-10, para. 10.
[64] Exhibit C-1-1, p. 11, para. 15.
[65] Exhibit C-1-1, p. 12, paras. 17-18.

million in incremental gas supply costs to meet its firm customer commitments.[66] As a result, EGD modified its gas supply planning processes to maintain maximum deliverability from its storage assets longer in the winter season. Moreover, delivered services are not guaranteed to be delivered (even if contracted on a firm basis) when needed, and cannot provide the flexibility to load shape (i.e., to match heat sensitive demand within the day) as the storage facilities are able to provide.[67]

40. *Upstream Pipeline Capacity Alternative.* To replace the deliverability of the CCS, Enbridge Gas would need to contract for 0.67 PJ/d of incremental pipeline capacity. ICF considered multiple upstream capacity options to meet the total requirements and determined that the incremental cost to ratepayers would be at least $4.7 billion higher than the cost of the Project.[68] In addition, since pipeline capacity would need to be contracted long-term with renewal rights, this alternative would be subject to market availability of transportation or require significant commitments to procure that capacity. Further, with less storage available at Dawn, commodity would need to be purchased to ensure balancing is available, which may require daily or weekly commodity purchases during peak demand periods and may therefore expose the Company's Gas Supply Plan to increased commodity price volatility.[69]

Enhanced Targeted Energy Efficiency ("ETEE") Alternative

41. This alternative considered the extent to which the proposed NPS 36 pipeline could potentially be reduced in size (by one nominal pipe size to NPS 30) through investment in ETEE and the cost for delivered supply needed to bridge the supply gap between the year that the system is constrained (2023) to the first year that the ETEE demand reductions can be expected to materialize (2027). Enbridge Gas determined that a reduction of 90 TJ/d would be required from any ETEE (or portfolio of the same) in

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[66] Exhibit B-2-1, p. 6, para. 14; Exhibit I.FRPO.23.

[67] Exhibit C-1-1, p. 12-13, paras. 18-21.

[68] As noted within Attachment 2 to Exhibit C-1-1, at Section 4.1, this incremental cost is conservatively offset by the assumption that the contracted capacity could be released for full basis value when not in use, providing some recovery of costs. This likely overestimates the value of the extra capacity on the capacity release market.

[69] Exhibit C-1-1, p. 14, para. 24.

order to reduce the proposed NPS 36 pipeline by one size to NPS 30. Even if feasible in terms of its availability and implementation (which is uncertain), an ETEE program delivering 90 TJ/d of demand reduction in the EGD rate zone is estimated to cost $980 million.[70] Sizing the proposed pipeline to NPS 30 would only avoid $15 million in materials and labour costs. However, the total costs of this alternative (delivered supply + ETEE + NPS 30) would range from $4.2 to $4.3 billion over 40 years.[71]

b. Facility Alternatives

42. Enbridge Gas assessed 4 facility alternatives capable of providing design day storage capacity equivalent to the existing seven CCS compressor units in question. The alternatives are: (i) NPS 36 pipeline (the Project), (ii) natural gas fired compression, (iii) electric drive motor compression, and (iv) liquified natural gas ("LNG") storage. The proposed NPS 36 pipeline is the lowest NPV alternative that provides a 1:1 capacity replacement and allows the consolidation of the compression fleet by utilizing Dawn hp while increasing the overall reliability of the storage system.[72]

NPS 36 Pipeline (the Project)

43. The NPS 36 pipeline provides a 1:1 replacement in design day storage system withdrawal capacity compared to the existing seven CCS compressor units. In effect, after station modifications at the CCS and the Dawn yard, the NPS 36 pipeline will provide equivalent storage injection capacity by using the existing compression units located within Dawn. NPS 36 is the optimal pipeline size since it represents the closest capacity equivalent in all respects compared to the existing CCS facilities at the lowest cost per unit of capacity. Further, via the proposed NPS 36 pipeline the Company will continue to maximize the capability of the integrated storage system at the Dawn Hub to provide the maximum deliverability potential on design day, as it does currently (the integrated storage system is designed to serve peak demand on

[70] Direct equivalent energy conversion of 90 TJ/d = 1.0 GW.
[71] Exhibit C-1-1, pp. 14-16, paras. 25-28, and p. 17, Table 1.
[72] Exhibit JT2.8, p. 3.

design day). This is critical as there is no further capability at the Dawn Hub to make up for the loss in deliverability on design day from the CCS resulting from the proposed retirement and abandonment of the seven CCS units; surplus transmission and storage compression cannot be used to increase deliverability from the integrated storage system on design day.[73] The Project will also enable the Company to utilize surplus Dawn compression hp throughout the balance of the year, excluding design day.[74]

44. The O&M costs for the pipeline are lower than the other facility alternatives and include future costs for inline inspection, integrity digs and repairs. The NPV for this alternative is ($200 million).[75] The capital cost of this alternative is lower than the other facility alternatives contemplated. Further, the proposed pipeline simplifies Enbridge Gas storage operations by reducing the amount of rotating assets and running equipment. This opportunity to replace compression with a pipeline alternative also reduces emissions through utilization of existing compression hp at Dawn which have a lower burn rate (at higher efficiency). The Company submits that this alternative is preferable.

45. To support its decision to proceed with the proposed NPS 36 pipeline Enbridge Gas completed QRAs to evaluate risk resulting from the new TR7 pipeline as a replacement,[76] as well the risk that would remain post-abandonment,[77] of the 7 CCS compressor units proposed to be retired and abandoned.

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[73] Exhibit JT2.8. Please also see the response at Exhibit I.STAFF.1

[74] Exhibit I.STAFF.1; The assets creating the [Dawn Storage] system constraint are the Dawn storage pools and gathering systems delivering a minimum suction pressure to Dawn C Plant (a centrifugal compressor) that is restricted in its ability to utilize any incremental hp due to its defined operating range (Exhibit JT2.8).

[75] Updated to $202 million in Exhibit JT2.7, Attachment 1, previously calculated as $200 million in Exhibit C-1-1, Attachment 1, Table 1.

[76] Enbridge Gas TR7 Pipeline Corridor Risk Assessment Report (Exhibit I.CME.1, Attachment 3).

[77] DNV Dawn-Corunna Modifications Project QRA Report (Exhibit I.CME.1, Attachment 4).

Natural Gas Fired Compression

46. This alternative includes a 1:1 replacement in total hp via the installation of two new Taurus 70 gas turbine compressor units[78] on the east side of the CCS,[79] station modifications at the CCS and Dawn Operations Centre, and retirement and abandonment of the existing compressor units and related facilities. The total estimated cost of this alternative is approximately $211 million.[80]

47. Natural gas fired compression has higher O&M costs compared to the proposed NPS 36 pipeline, based on standard operating practices to maintain the compressors, including: routine maintenance, engine overhauls, and replacement of mechanical parts and equipment.[81] Further, the cost of compressor fuel and federal carbon pricing cost associated with the same also contribute to the higher O&M costs. The NPV of this alternative is ($212 million). The alternative is higher in capital cost than the proposed Project, and leaves the new compressors without full LCU coverage.[82] Absent full LCU coverage, should one of the new Taurus 70 units fail on design day, the remaining units would be unable to fully compensate (in terms of hp) which would force the Company to seek alternative sources of supply to makeup for any remaining shortfall (e.g., market-based services which subject ratepayers to incremental availability, price volatility, and contracting risks). As such, the Company determined that this alternative is not preferable.[83]

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[78] Two compressor units are required, since retiring the seven compressor units (K701-3 and K705-8) with a total hp of 22,500 and replacing with only 1 Taurus 70 (~12,000 hp) would leave the integrated storage system at a deficit of deliverability on Design Day (Exhibit JT2.8. p. 3).

[79] In preparing the response to Exhibit I.FRPO.25, Enbridge Gas found an error in its pre-filed evidence. New compression at the CCS would be located on the east side of Tecumseh Rd, not the west side. (Exhibit I.FRPO.25, p. 2).

[80] Exhibit C-1-1, p. 18, para. 30.

[81] Exhibit I.EP.12.

[82] Exhibit I.ED.10 b).

[83] Exhibit C-1-1, p. 18, para. 32.

Electric Drive Motor Compression

48. This alternative provides a 1:1 replacement in total hp via installation of two new Spartan e90 electric motor drive ("EMD") compressor units[84] on the east side of the CCS, station modifications at CCS and Dawn, and retirement and abandonment of the existing compressor units and related facilities. This alternative also includes additional costs for a new 27.7 KVA substation and backup generator to provide reliable power for the components of the EMD compressor units, but not the EMD compressors themselves. This alternative has been estimated to cost approximately $217 million.[85]

49. EMD compression has higher O&M costs compared to the NPS 36 pipeline based on standard operating practices to maintain the compressors including: routine maintenance, overhauls, replacement of mechanical parts and equipment and annual electricity usage.[86] The NPV for this alternative is ($289 million).[87] The capital cost of this alternative is higher than the proposed Project, and the alternative leaves the new compressors without full LCU coverage. As such, the Company determined that this alternative is not preferable.[88] The cost estimate did not include the cost of a backup gas driven motor to run the EMD in event of a hydro grid failure that would make this alternative further uneconomic compared to the proposed Project.[89]

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[84] A new compressor in the 10 MW range (Spartan e90) could replace up to four existing reciprocating (K700 series) compressors (Exhibit I.FRPO.25 c) ii). Two compressor units are required, since retiring the seven compressor units (K701-3 and K705-8) with a total hp of 22,500 and replacing with only 1 Spartan e90 (~12,000 hp) would leave the integrated storage system at a deficit of deliverability on Design Day. Any scenario (including installing only one Spartan e90) that does not replace the full capacity of the seven compressor units (and relies on procuring market-based storage vs. maintaining cost-based storage at Dawn) is significantly more expensive than the Project (Exhibit JT2.8. pp. 3-4).

[85] Exhibit C-1-1, p. 19, para. 33.

[86] Exhibit I.EP.12.

[87] In the assessment of this alternative as described at Exhibit C-1-1, the Company had not accounted for all global adjustment and delivery charges. To account for these additional amounts, a hydro rate of $0.18/kWh (increased from $0.148/kWh) is more appropriate, which increases the NPV of the EMD alternative from $270 million to $289 million (Exhibit I.SEC.13, p. 3).

[88] Exhibit C-1-1, p. 19, paras. 34-35.

[89] Exhibit I.FRPO.28.

50. It is important to note that the installation of a single new compressor is not a feasible alternative since it continues to leave a single point of failure and the new compressor without full LCU coverage (see similar discussion in paragraph 47 above). It also fails to address the fundamental Project need related to reliability and safety risks.[90] Upon assessing the permutations of CCS compressor units replaced (in terms of hp) by a single Spartan e90 or Taurus 70, Enbridge Gas determined that even in a scenario where up to five existing units are abandoned, the resulting increase in physical separation between the remaining CCS compressor units fails to eliminate the excessive process safety risk exposure for operators and mechanics.[91]

LNG Storage

51. An above ground LNG storage facility, including incremental compression to fill and empty the facility, was preliminarily evaluated. Relative to the existing compressor units at the CCS facility, at an estimated cost of approximately $1 billion, while an LNG storage facility could replace an equivalent amount of storage deliverability, it could not replace an equivalent amount of storage injection capacity.[92] An LNG facility would not provide the equivalent operational requirements of the existing underground storage and would cost approximately 5 times the capital cost of the proposed Project.[93]

c. Repair + Replace Alternative

52. This alternative involves replacing the capacity of only units K701-K703 with an NPS 20 pipeline (at a capital cost of $160 million) that follows the same running line and requires the same station modifications as the Project. Compressor units K705-K708

[90] Exhibit I.ED.10 b); Exhibit I.SEC.13, p. 2.
[91] Exhibit I.ED.10 c).
[92] Exhibit C-1-1, p. 20, paras. 39-40.
[93] Exhibit C-1-1, pp. 20-21, para. 41.

would remain in service, requiring continued reactive repair, maintenance and support and subjecting ratepayers to ongoing and increasing risk of shortfall/outage.[94]

53. As noted above, units K705-K708 account for 41% of the available compressor power at the CCS and face both increasing risk of unplanned outage and challenges to sourcing parts. Both aspects lead to increased compressor unit downtime and further exacerbate reliability issues due to increased runtime on backup units. In addition to the costs of unplanned outages, planned maintenance activities estimated at $9.7 million are required over the next 10 years to address known risks to units K705-K708.[95] Leaving units K705-K708 in operation exposes ratepayers to increased interruption risk to storage withdrawal and injection operations and to significant maintenance costs.[96]

54. Further, leaving units K705-K708 in operation does not address the employee safety risk associated with the number of compressor units and building occupancy in CCS compressor buildings 1 and 2. There is no risk reduction associated with building 2, and by leaving unit K705 in building 1 there is potential for multiple units to be operating in the building at the same time.[97] In any event, the NPV of the Repair + Replace alternative over a 40-year term is ($208 million) which is more expensive than the proposed Project.[98]

55. Significant cost savings are also realized by replacing all seven existing compressor units at one time with the proposed NPS 36 pipeline. In addition to the cost of the Repair + Replace alternative and assuming that units K705-K708 were replaced or "phased-in" at some point in the near future after the Repair + Replace alternative is constructed, this alternative would require significant incremental investments to replace units K705-K708 at that time; either a new Taurus 70 compressor (increasing

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[94] Exhibit C-1-1, p. 21, para. 42.

[95] Including risks related to pressure control and overpressure protection, vibration detection equipment, valves, glycol systems, jacket water coolers, overhauls and cam upgrades (Exhibit C-1-1, p. 21, para. 43).

[96] Exhibit C-1-1, p. 21, para. 43.

[97] Exhibit C-1-1, p. 22, para. 44.

[98] Exhibit I.ED.9 a).

total cost to $321 million), a new Spartan e90 compressor (increasing total cost to $329 million), or an additional NPS 30 pipeline (increasing total cost to $300 million).[99]

56. Phasing in the retirement of the seven CCS compressor units would cost between $300-$333 million (compared to the Project at $206 million) and is not cost-effective. Furthermore, this alternative does not address the imminent need to address the obsolescence, reliability and safety issues at CCS. Further, the RAM Study indicates an increasing frequency of failures for these units in the future, and Enbridge Gas anticipates that the pace of failure and replacement under such a strategy could be rapid and not be within the Company's, ratepayers' and the OEB's control.[100]

E. Project Costs & Economics

57. Excluding indirect overheads and loadings, the total estimated cost of the Project is $206.4 million, as shown in Table 1 below.[101]

Table 1

Item #	Description	Pipeline Costs	Ancillary Costs	Total Costs
1.0	Materials	$11,800,354	$36,643,592	$48,443,946
2.0	Construction & Labour	$51,310,846	$28,993,020	$80,303,866
3.0	External Permitting & Lands	$15,322,222	$0	$15,322,222
4.0	Outside Services	$19,230,385	$15,702,325	$34,932,710
5.0	Direct Overheads	$1,295,000	$0	$1,295,000
6.0	Contingency	$13,180,351	$10,816,348	$23,996,699
7.0	IDC	$2,093,000	$0	2,093,000
8.0	**Project Cost**	**$114,232,158**	**$92,155,285**	**$206,387,443**
9.0	Indirect Overheads & Loadings	$26,277,051	$18,085,209	44,362,260
10.0	**Total Project Costs**	**$140,509,209**	**$110,240,494**	**$250,749,703**

NOTE:
The total costs set out in Table 1 include abandonment of the existing seven CCS compressor units K701-K703 and K705-K708 amounting to $14.5 million.

58. As the Project is driven by the need to address system obsolescence, reliability and personnel safety risks, a Discounted Cash Flow report has not been completed. The Project will create design day storage capacity equivalent to the capacity lost due to

99 Exhibit I.SEC.13, p. 2.

100 Exhibit I.SEC.13, p. 3, and p. 4, Table 1.

101 Exhibit D-1-1, p. 1, para. 3 and Table 1.

the retirement and abandonment of the existing 7 CCS compressor units. Importantly, no incremental storage capacity (space, deliverability or injections) will be created by the Project.[102]

59. The pipeline cost is approximately $6 million per km based on pipeline project costs of $114,232,158 and a pipeline length of 19.173 km. This cost is comparable to similar diameter pipelines situated on agricultural lands. Having said that, project costs cannot be directly compared without considering all unique contributing factors at the time they are estimated or incurred.[103]

60. As per OEB Decision and Order (EB-2020-0256) dated April 22, 2021, the allocation of costs between utility and non-utility operations will be addressed as part of Enbridge Gas's 2024 rebasing application.[104]

61. The proportion of the Project cost to be allocated to the utility business is 100% as the Project replaces the existing capacity of the original assets proposed to be retired and abandoned that are currently allocated 100% to the utility business. This accounting treatment is consistent with the OEB's determinations in the NGEIR proceeding (EB-2005-0551) that the capacity dedicated to providing storage services to EGD rate zone in-franchise customers would remain regulated, and thus all existing EGD rate zone Tecumseh storage capacity held at that time would be treated as such. This treatment would not be any different if any of the alternatives assessed by the Company (including facility and non-facility/supply-side alternatives) were selected instead of the proposed Project.[105]

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[102] Exhibit D-1-1, p. 2, para. 7; Exhibit KT1.3. As the Project is a replacement/renewal investment there will be no incremental revenues generated as a result of its approval and construction. Therefore, a DCF report is not appropriate and has not been completed.

[103] Exhibit I.EP.14 d).

[104] Exhibit I.Staff.9 b).

[105] JT1.3 and JT2.5.

F. Engineering and Construction

62. As noted above, the Project includes:
    i. the construction of approximately 20 km of NPS 36 pipeline from the Dawn Operations Centre to the CCS;
    ii. work within the CCS to decommission seven existing compressor units and to connect the new NPS 36 pipeline to CCS; and
    iii. removal of the Tecumseh measurement facilities from within the Dawn Operations Centre (including demolition of the building and removal of all measurement equipment, piping, and telemetry).[106]

63. Enbridge Gas will construct the proposed pipeline in compliance with engineering design, its current construction procedures and specifications, environmental mitigation identified in the ER, permit conditions and commitments to regulators and landowners.[107]

64. Pipeline materials need to be ordered in 2022 to meet an in-service date of November 1, 2023. Construction of the pipeline is expected to commence by July/August of 2023. The construction schedule is designed to take advantage of drier summer months to minimize the impact of construction on agricultural lands and other features, such as watercourses.[108]

65. All design, installation and testing of the proposed pipeline will be in accordance with the specifications outlined in Enbridge Gas's Construction and Maintenance Manual ("Specifications") and with the requirements of Ontario Regulation 210/01 (Oil and Gas Pipeline Systems) under the *Technical Standards and Safety Act, 2000*. The design meets or exceeds the requirements of CSA Z662 Standard for Oil and Gas Pipeline Systems (latest edition) in accordance with the Code Adoption document under the Ontario Regulations.[109]

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[106] Exhibit E-1-1, p. 1.
[107] Exhibit E-1-1, pp. 4-5, para. 21.
[108] Exhibit E-1-1, p. 2, paras. 6-8.
[109] Exhibit E-1-1, p. 2, paras. 9-10.

66. Enbridge Gas will construct the Project using qualified construction contractors and employees who will follow approved construction Specifications and any site-specific adjustments that may be required. All construction, installation and testing of the Project will be witnessed and certified by a valid Gas Pipeline Inspection Certificate Holder or Professional Engineer.[110] The method of construction will be a combination of open trench and trenchless technology.[111] Restoration and monitoring will be conducted through 2024 to ensure successful environmental mitigation for the Project.[112]

67. All necessary permits, approvals and authorizations will be obtained by Enbridge Gas at the earliest appropriate opportunity. Enbridge Gas expects to receive all required approvals prior to commencing construction of the Project. Enbridge Gas will assign inspection staff to ensure that contractual obligations between Enbridge Gas and the pipeline contractor, provincial ministries, municipal government and landowners are complied with.

G. <u>Environmental Matters</u>

68. Enbridge Gas has undertaken a comprehensive route evaluation and environmental and socio-economic impact study for the Project to select the preferred route ("PR") and identify relevant impacts and mitigation measures where appropriate. By following its standard construction practices and adhering to the recommended mitigation measures, the construction and operation of the Project will have negligible impacts on the environment. The study also indicates that no significant cumulative effects are anticipated from the development of the Project.[113]

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[110] Exhibit E-1-1, p. 4, para. 16.

[111] See Exhibit E-2-1 for details regarding the techniques and methods of construction.

[112] Exhibit E-1-1, p. 4, para. 17. Also see JT1.16, which outlines the construction specifications for construction practices used on agricultural lands that apply to the Project.

[113] Exhibit F-1-1, pp. 3-4, para. 9.

69. Led by Stantec Consulting Limited ("Stantec"), the study included an integrated consultation program, which was designed to receive input from interested and potentially affected parties, including Indigenous communities.[114]

70. The results of the study are documented in the Environmental Report ("ER").[115] In addition to identifying a PR that minimizes potential environmental impacts, the ER sets out a detailed review of environmental features along the PR (and the potential environmental impacts on these features), establishes mitigation and protective measures to minimize or eliminate potential environmental impacts of the Project, and identifies any necessary supplemental studies and monitoring/contingency plans.[116]

71. The ER was forwarded to the Ontario Pipeline Coordination Committee in September 2021, and copies of the ER were also sent to all affected municipalities, conservation authorities, Kettle and Stoney Point First Nation, Aamjiwnaang First Nation, Walpole Island First Nation, Chippewas of the Thames, and the Oneida Nation of the Thames. Summaries of the comments received together with responses from Enbridge Gas and/or Stantec are set out in the Application.[117]

72. Enbridge Gas will comply with all mitigation measures recommended in the ER, including the development of an Environmental Protection Plan prior to construction start that incorporates recommended mitigation measures. Mitigation measures will be communicated to the construction contractor prior to the commencement of construction of the Project. A qualified Environmental Inspector or suitable representative will be available to assist the Project Manager in seeing that mitigation measures identified in the EPP as well as any additional permitting requirements

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[114] Exhibit F-1-1, p. 1, para. 3. Notably, virtual open house information sessions were held in 2021 to inform and solicit input from landowners, tenants and the public with respect to the Project (Exhibit F-1-1, p. 2, para. 5).

[115] https://www.enbridgegas.com/about-enbridge-gas/projects/dawn-corunna-project/. Also see Exhibit F-1-1, pp. 4-6 which highlights various pertinent aspects of the ER.

[116] Exhibit F-1-1, p. 2, para 4.

[117] Exhibit F-1-1, Attachments 2, 3 and 4.

and/or conditions of approval are adhered to and that commitments made to the public, landowners and agencies are honoured.[118]

H. Land Matters

73. The proposed 20 km pipeline requires approximately 95.68 hectares (236.44 acres) of total area, which is comprised of permanent easement and temporary land use. Enbridge Gas plans to acquire the land rights to 42.14 hectares (104.13 acres) of permanent easement. Enbridge Gas will also require approximately 53.54 hectares (132.31 acres) of temporary land use for construction and topsoil storage purposes.[119]

74. When constructing an NPS 36 pipeline, Enbridge Gas requires a 23 m easement to ensure the safety of the pipeline facilities and the public (including landowners) and to provide the necessary land rights and working space for pipeline maintenance following construction.[120] The forms of agreement proposed by Enbridge Gas have been previously reviewed and approved by the OEB.[121]

75. Enbridge Gas is implementing a comprehensive program to provide landowners, tenants and other interested parties with information regarding the Project. Information was previously distributed through correspondence and meetings with the public. Where formal public meetings were held, in conjunction with the ER (as discussed above), directly affected landowners and agencies were invited to participate by letter, and the general public was invited to participate through newspaper advertisements.[122] Enbridge Gas has also initiated meetings with landowners to obtain early access to complete survey work.

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[118] Exhibit F-1-1, p. 3, para. 8.

[119] Exhibit G-1-1, p. 1, para. 4 (updated via letter to the OEB on July 26, 2022). All of the properties and the approximate dimensions of permanent and temporary easements required for the Project are outlined in Exhibit G-1-1, Attachment 2.

[120] JT2.27, p. 2.

[121] These are the form of Pipeline Easement and from of Temporary Land Use Agreement filed at Exhibit G-1-1, Attachments 3 and 4. Also see Enbridge Gas's proposed form of Letter of Understanding at Exhibit L-1-1, Attachment 1.

[122] Exhibit G-1-1, p. 3, para. 9.

76. Enbridge Gas has a comprehensive and proven landowner relations program in place. Key elements of this program include complaint tracking and assignment of a lands agent to: (i) ensure that commitments made to landowners are fulfilled; (ii) address landowner questions/concerns as promptly as possible; and (iii) act as a liaison between landowners, the Pipeline Contractor and Enbridge Gas Project personnel.[123]

77. At the time of submitting this AIC, Enbridge Gas is in the process of negotiating with the Canadian Association of Energy and Pipeline Landowner Associations' Dawn Corunna Landowner Committee ("CAEPLA-DCLC"), with a negotiation meeting set between the two parties for September 9, 2022. As directed by the OEB, the two parties will file a joint letter by September 15, 2022 to advise regarding any settlement reached and/or any outstanding issues that have not been settled.[124]

I. <u>Indigenous Consultation</u>

78. Enbridge Gas has carried out a comprehensive process to achieve meaningful engagement and dialogue with Indigenous groups (First Nations and Métis) that are potentially affected by the Project. Throughout this process, Enbridge Gas has strived to build an understanding of potentially affected interests, ensure regulatory requirements are met, mitigate or avoid potential impacts on Indigenous interests/rights, and provide mutually beneficial opportunities where possible.

79. The design of the Indigenous engagement program was based on adherence to the OEB's *Environmental Guidelines for the Location, Construction, and Operation of Hydrocarbon Pipelines and Facilities in Ontario, 7th Edition, 2016* (the "Guidelines") and Enbridge Inc.'s company-wide Indigenous Peoples Policy.[125]

80. In a February 19, 2021 letter to Enbridge Gas, the Ontario Ministry of Energy ("MOE") delegated the procedural aspects of the duty to consult to the Company for the Project

[123] Exhibit G-1-1, p. 3, para. 11.
[124] OEB letter dated August 2022 re: Joint Letter on Status of Settlement Negotiations.
[125] Exhibit H-1-1, p. 2, para. 6.

and identified five Indigenous communities to be consulted in relation to the Project.[126] Enbridge Gas provided its Indigenous Consultation Report ("ICR")[127] to the MOE in March 2022, and has since kept the MOE apprised of Indigenous consultation matters related to the Project.[128] The MOE will review Enbridge Gas's consultation with Indigenous groups and provide its decision as to whether Enbridge Gas' consultation has been sufficient.[129]

81. Enbridge Gas conducts its Indigenous engagement generally through phone calls, in-person meetings, mail-outs, open houses and email communications. During these engagement activities, Enbridge Gas representatives provide an overview of the Project, respond to questions and concerns, and address any interests or concerns expressed by Indigenous communities to appropriately avoid or mitigate any Project-related impacts on Indigenous or treaty rights. Capacity Funding is offered to ensure there are reasonable resources for Indigenous communities to meaningfully participate in consultation. In addition, Enbridge Gas discusses with Indigenous communities options to accommodate any potential adverse effects the Project may have on Indigenous or treaty rights. To accurately record engagement activities and ensure follow-up by either the Crown or Enbridge Gas, applicable supporting documents are tracked and documented.[130] Going forward, Enbridge Gas will continue to pursue meaningful dialogue and engagement throughout the life of the Project to ensure any potential impacts on Indigenous or treaty rights are addressed, as appropriate.[131]

[126] Exhibit H-1-1, p. 1, para. 4 and Attachment 2.
[127] Exhibit H-1-1, Attachment 6.
[128] Exhibit JT2.33.
[129] Exhibit H-1-1, p. 2, para. 5.
[130] See Exhibit H-1-1, Attachment 5 for a summary of Enbridge Gas's Indigenous engagement activities for the Project.
[131] Exhibit H-1-1, p. 4, para. 12.

J. Relief Requested

82. Based on the foregoing, Enbridge Gas respectfully requests that the OEB issue an Order granting leave to construct the Project pursuant to section 90 of the Act and an Order approving the forms of Pipeline Easement and Temporary Land Use Agreement set out at Exhibit G-1-1, Attachments 3 and 4, pursuant to section 97 of the Act.

All of which is respectfully submitted this 6th day of September 2022.

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Charles Keizer
Counsel to Enbridge Gas